BEFORE THE

STATE OF DELAWARE

PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) | |
| CHESAPEAKE UTILITIES CORPORATION | ) | |
| FOR APPROVAL OF MODIFICATIONS | ) | PSC Docket No. 11-384F |
| TO ITS GAS SERVICE RATES (“GSR”) TO | ) | |
| BE EFFECTIVE NOVEMBER 1, 2011 | ) | |
| (Filed September 1, 2011) | ) | |

DIRECT TESTIMONY OF

ANDREA C. CRANE

ON BEHALF OF

THE DIVISION OF THE PUBLIC ADVOCATE

February 24, 2012

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## I. STATEMENT OF QUALIFICATIONS

**Q. Please state your name and your business address.**

A. My name is Andrea C. Crane and my business address is 90 Grove Street, Suite 211, Ridgefield, CT 06877. (Mailing address: PO Box 810, Georgetown, Connecticut 06829)

**Q. By whom are you employed and in what capacity?**

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation and regulatory policy. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various financial studies relating to utility rates and regulatory policy. I have held various positions of increasing responsibility with The Columbia Group, Inc. since I joined the firm in January 1989. I became President of the firm in 2008.

**Q. Please summarize your professional experience in the utility industry.**

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

**Q. Have you previously testified in regulatory proceedings?**

A. Yes, since joining The Columbia Group, Inc., I have testified in over 350 proceedings in the states of Delaware, Arkansas, Arizona, Connecticut, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia, and the District of Columbia. These proceedings involved gas, electric, telephone, water, wastewater, solid waste, cable television and navigation utilities. A list of dockets in which I have filed testimony since January 2008 is included as Appendix A.

**Q. What is your educational background?**

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. On September 1, 2011, Chesapeake Utilities Corporation ("CUC" or "Company") filed an Application ("Application") with the State of Delaware, Public Service Commission ("PSC" or "Commission") requesting approval for a change in its Gas Service Rate ("GSR") factors for the period November 1, 2011 through October 31, 2012.

The Columbia Group, Inc. was engaged by the State of Delaware, Division of the Public Advocate ("DPA") to review the Company's Application; to identify areas of possible concern to Delaware ratepayers; and to develop recommendations for consideration by the

Commission. In developing my recommendations, I reviewed the Company's Application, the testimony and exhibits filed by the Company, and the responses to data requests propounded upon CUC by the DPA and by the Staff of the Public Service Commission ("Staff"). I also reviewed prior PSC orders and other documents useful in an analysis of the Company's filing.

## III. SUMMARY OF CONCLUSIONS

**Q. Please summarize your conclusions and recommendations.**

A. Based on my review of CUC's filing and testimony, on the discovery activities that have been conducted, and on my experience in the area of regulatory accounting and policy, my conclusions and recommendations are as follows:

- CUC has frequently executed agreements for new capacity or agreements relating to management of its assets without providing proper notification to Staff and/or DPA.
- The Company's affiliate, Eastern Shore Natural Gas ("ESNG") has a direct financial interest in CUC acquiring additional ESNG capacity, a situation that may not be in the best interests of ratepayers.
- CUC has acquired ESNG capacity in eastern Sussex County based on optimistic forecasts of future growth.
- It appears that the Company has adequate capacity, both upstream capacity and capacity from ESNG, for the foreseeable future.
- In its Annual Supply Plans, CUC should identify the need for all new capacity

additions well in advance of executing agreements for new capacity.

- The Company's design day forecasting methodology should be reviewed prior to the Company acquiring any additional capacity.
- If it chooses to continue to utilize an Asset Manager, in the next GSR filing CUC should provide a detailed timeline for soliciting a new Asset Management Agreement.
- Any new Asset Management Agreement should contain a requirement for full disclosure of all transactions impacting affiliates.
- The Company's gas hedging program is working well. Given the recent decline in natural gas prices, the parties will continue to discuss whether CUC should further accelerate the purchase of any gas hedges. In addition, the Company should continue to monitor results simulating dollar-cost averaging to determine if dollar-cost averaging should be adopted.
- The GSR factors proposed by CUC in its Application should be approved.

## IV. <u>BACKGROUND OF THE APPLICATION</u>

**Q. Please provide a brief background of the Company's filing.**

A. On September 1, 2011, CUC filed its GSR factors for the period November 1, 2011 through October 31, 2012. The Company requested the following modifications in rates:

| Rate Schedule | Proposed GSR per Ccf | Prior GSR per Ccf |
|---|---|---|
| RS-1, RS-2, GS, MVS, LS | $1.027 | $1.035 |
| GLR, GLO | $0.830 | $0.863 |
| HLFS | $0.592 | $0.668 |
| Firm Balancing Rate (LVS) | $0.063 | $0.054 |
| Firm Balancing Rate (HLFS) | $0.021 | $0.010 |
| Firm Balancing Rate (ITS) | $0.001 | $0.001 |

On September 20, 2011, the PSC issued Order No. 8042, allowing the GSR factors to become effective with meter readings on and after November 1, 2011, on an interim basis subject to refund. The rates proposed in the Application resulted in a decrease of approximately 1% or $0.50 per month, for an average residential heating customer using 700 Ccfs per year relative to the rates that were previously in effect. During the winter heating season, a typical customer using 110 Ccfs per month experienced a decrease of approximately $0.90 per month or 1% relative to the prior rates. An RS-2 customer using 120 Ccfs per month experienced a decrease of approximately 1% or $1.00 per winter month.

## V. DISCUSSION OF THE ISSUES

### A. Background of the Procurement Process

**Q. Can you provide a brief background of CUC and its procurement process?**

A, CUC provides service to approximately 41,430 customers, approximately 91.6% of which are residential customers. CUC's customers are located in southern New Castle, Kent and Sussex Counties. The Delaware Division is one of three natural gas divisions. CUC also provides natural gas distribution service to Maryland's eastern shore and to several counties in Florida. CUC also provides electric distribution services to approximately 31,000 customers in four counties in Florida.

The Delaware Division is connected to only one natural gas pipeline, Eastern Shore Natural Gas ("ESNG"), which is an affiliate. There are no other pipelines in the immediate vicinity. The Delaware Division has transportation entitlements with ESNG that in turn are supported by upstream transportation entitlements and storage agreements with Transcontinental Gas Pipeline Corporation ("Transco"), Columbia Gas Transmission Corporation ("Columbia"), Columbia Gulf Transmission Company ("Gulf"), and Texas Eastern Transmission Corporation ("TETCO"). Hence, all gas delivered to the Delaware Division's customers must flow through the pipeline of its affiliate, ESNG. ESNG is regulated by FERC. The Company's upstream transportation assets are managed by a third-party pursuant to an Asset Management Agreement. The vast majority of the Company's commodity gas supply is also purchased through the Asset Manager.

In addition to its regulated activities, CUC also undertakes unregulated natural gas marketing activities through Peninsula Energy Services Company, Inc. ("PESCO"); distributes propane on the Delmarva Peninsula, in Southeastern Pennsylvania and in Florida; and markets propane to wholesale customers primarily in the southeastern portion of the United States.

The Delaware Division had been growing very rapidly until the last several years. From 2002-2008, residential customers in the Delaware Division grew by approximately 8.7% per year, far exceeding the national average of 2-3%. However, growth slowed in recent years, presumably due to the downturn in general economic conditions and a slowdown in the housing industry. Residential growth over the past three years has averaged 2.74%, which still reflects healthy growth for a regulated gas utility, especially in the current economic environment.

Prior to the current economic downturn, the Company had projected significant growth in eastern Sussex County and had taken steps to obtain additional pipeline capacity to serve this area. Unfortunately, this projected growth, for the most part, has not materialized, especially with regard to residential housing. The issue of expansion in eastern Sussex County is closely aligned with the expansion of pipeline capacity from ESNG. While the Delaware Division is regulated by the PSC, ESNG is regulated by the Federal Energy Regulatory Commission ("FERC"). ESNG must obtain approval from FERC before expanding its pipeline into eastern Sussex County and FERC is unlikely to approve such an expansion without a showing that sufficient customer demand is present in the area. Moreover, it is difficult to demonstrate that customer demand exists unless a natural gas distribution system is available. So, to some extent, ESNG must rely upon the Delaware Division in order to have expansion in eastern Sussex County approved, while the Delaware Division must rely upon ESNG's pipeline expansion in order to justify its expansion into new areas of Sussex County. This situation is hardly ideal when the two entities involved have common ownership, as is the case here.

**Q. How do the rates being requested in this case compare with the rates requested by CUC in last year's filing?**

A. The GSR rates represent a slight decrease over the rates proposed in last year's filing. The Company's projected commodity costs are approximately $0.60 Mcf, or almost 30%, less than the commodity costs projected for the prior GSR period while fixed costs are relatively stable. However, the Company's GSR also reflects over 16% fewer sales volumes relative to the prior GSR filing. The proposed GSR rates also include recovery of a projected under-collection at October 31, 2011 of $286,279. The actual under-collected balance was $1,246,136.

**Q. How do CUC's GSR rates compare with the supply rates of other natural gas utilities?**

A. As shown in the response to DPA-51, CUC's gas sales rate for residential heating customers continues to be very high relative to other natural gas companies in the area. A rate comparison provided in this response indicates that Chesapeake's rates exceed the rates of most other natural gas companies in the area, including Delmarva Power and Light Company ("DPL"). Out of the twelve companies included in Chesapeake's comparison, only one, Eastern Utilities Corporation, has higher rates than Chesapeake. The rates for eight of the twelve companies in the survey are under $8.00 per Mcf. CUC's rates have historically been higher than the rates of most other natural gas utilities in the area. One reason for these higher rates is the fact that CUC is not directly connected to any pipeline except for its affiliate, ESNG. Therefore, in order to access natural gas, it generally has had to acquire capacity on two pipelines, ESNG and an upstream pipeline, to transport gas to its service territory.

**B. <u>Issues From Prior Case</u>**

**Q. What issues did you raise in last year's GSR proceeding?**

A. My testimony in that case contained the following conclusions and recommendations:

- I found that the Company had not justified the TETCO capacity costs, or the associated ESNG costs, included in its GSR filing. Therefore, I recommended that these costs be disallowed unless the Company demonstrated in its rebuttal testimony that this arrangement was less expensive than continuing to acquire bundled peaking service.
- I recommended that if the Commission permitted CUC to recover any of the TETCO capacity costs from ratepayers, then CUC should be required to maximize capacity release revenues associated with this capacity. Moreover, I recommended that this capacity should not be marketed pursuant to the current Asset Management Agreement but should be marketed directly by the Company.
- I recommended that CUC obtain input from the parties on any Request for Proposal issued for Asset Management Services and seek input from the parties prior to signing a new agreement for Asset Management Services, or an extension of the

current agreement.

- I recommended that in the future the Company should solicit input from the parties prior to entering into any new capacity agreements, including both upstream capacity and ESNG capacity. I recommended that the Company notify the parties during each quarterly gas hedging meeting if they were considering entering into new capacity agreements and provide financial justification for all new capacity agreements.
- I recommended that if the DPA's appeal of the Commission's decision in PSC Docket No. 08-269F was successful, then the GSR should be credited for the difference between the amount paid by PESCO for ESNG capacity and the amount charged to Delaware ratepayers for this same capacity. This appeal was denied in June 2011.
- I recommended that the Company continue to follow its gas hedging plan, as amended in PSC Docket No. 09-398F, and to meet with the parties quarterly to review the results of its hedging activities.
- I recommended that the Company's GSR reflect amortization through February 2016 of the Eastern Shore Energylink Expansion ("ESNG E-3) Project precertification costs, net of deferred tax benefits credited to ratepayers.
- I recommended that the PSC require CUC to continue to provide information regarding the impact on the GSR of forecasted sales using a thirty-year average for normal weather.

**Q. How were issues raised in last year's GSR filing resolved?**

A. The most significant provision in the Settlement Agreement in the last GSR proceeding was the requirement that the Company file its comprehensive Long-Term Supply and Demand Strategic Plan ("Supply Plan") or an annual basis. Previously, the Company had filed its Supply Plan every two years. The expectation is that the filing of an Annual Supply Plan will alleviate some of the concerns of the parties that Chesapeake is acquiring additional capacity between GSR cases that may not be in the best interest of Delaware ratepayers. The first Annual Supply Plan was filed on September 1, 2011.

Other provisions of the Settlement Agreement included:

- Chesapeake was permitted to recover the costs associated with the incremental TETCO capacity. The Company agreed to credit 100% of any capacity release revenues received by the Company outside of its Asset Management Agreement to ratepayers. It also agreed to informally provide additional information to Staff and DPA supporting its decision to acquire this capacity as well as additional information relating to the costs of bundled peaking relative to the cost of the new capacity.

- Chesapeake agreed to track a dollar-cost averaging framework for its gas procurement program for possible implementation at the time of its next GSR filing.

- Chesapeake agreed to make a good faith effort to be more selective in the information it claimed was confidential and to provide redacted versions of documents containing both confidential and non-confidential information.

- The Company agreed to provide an annual status report on its expansion activities in eastern Sussex County as part of its main extension report filed in the spring of each year.

- The Company agreed to provide information on its Asset Management procurement process.

- The Company agreed a) to continue to notify the parties of any supplier refunds, b) to continue to include information in future GSR filings on steps taken to mitigate the impact of gas costs, c) to continue to provide information in its GSR filings on volumes, costs, and margins relating to interruptible sales, and d) to continue to calculate the impact on its GSR of a thirty-year degree day average, if requested in discovery.

In addition, during the course of that proceeding, the Company's affiliate, ESNG, filed a revised tariff with FERC relating to the collection of ESNG E-3 precertification costs. Pursuant to that tariff, the repayment period was reduced from 25 years to approximately 7 years, which significantly reduced the interest payments paid by Delaware customers. In addition, ESNG agreed to allocate a proportionate share of the deferred tax benefit to CUC. This revised tariff was deemed to be an acceptable resolution of the ESNG E-3 issue that had been raised by DPA and Staff. Overall, the revised tariff reduced the amounts due from Chesapeake ratepayers from approximately $3.8 million to approximately $1.5 million.

### C. <u>General Concerns</u>

**Q. What general concerns do you have regarding the Company's gas procurement activities?**

A. Many of the decisions that currently impact the Company's GSR rates were made with little or no input from Staff or DPA, but were presented to the parties as done deals that had to be funded by ratepayers. For example, CUC entered into a precedent agreement with its affiliate, ESNG, for capacity on the E-3 Project, a proposed pipeline expansion project from Cove Point, Maryland to the Delmarva peninsula that would have crossed under Chesapeake Bay. The termination of this project by ESNG resulted in significant precertification costs being charged to Delaware ratepayers, in spite of the fact that the PSC had never approved CUC's participation in the project.

CUC also entered into an Asset Management Agreement for management of its Transco and Columbia assets, including capacity releases, without obtaining the input of the parties or of the Commission. CUC also increased its capacity on the ESNG pipeline, including in areas of eastern Sussex County, without justifying the need for this additional capacity in spite of the fact that these incremental capacity costs are being passed along to ratepayers through higher fixed charges in the GSR. Nor did CUC solicit input from the parties prior to executing precedent agreements for substantial upstream capacity from TETCO. Moreover, all upstream capacity requires an interconnection to ESNG, resulting in the need for additional ESNG capacity to transport the gas received from TETCO, thus providing a direct financial benefit to CUC's affiliate.

**Q. Have the parties attempted to impose more stringent notification requirements on CUC?**

A. Yes, in prior cases, the parties have negotiated settlements with CUC that required CUC to keep the parties informed about various activities, such as increased capacity allocations on ESNG or efforts relating to soliciting a new Asset Management Agreement. Since the last case, Chesapeake did provide two such notifications to Staff and DPA regarding precedent agreements with TETCO and ESNG effective November 2013. However, CUC failed to notify Staff and DPA of its decisions to extend the Asset Management Agreement and to assign the TETCO capacity to the Asset Manager until after it had executed these actions, as discussed in more detail below. Therefore, while there has been some improvement in Chesapeake's notification of the parties, there are still significant problem areas.

**D. <u>Capacity Additions</u>**

**Q. Over the past few years, has CUC acquired significant additional pipeline capacity?**

A. Yes, it has. As discussed previously, all gas that ultimately serves CUC's ratepayers must flow through the pipeline of the Company's affiliate, ESNG, which is the only pipeline directly connected to CUC. In addition, the Company has upstream capacity on several pipelines that actually transport the gas to an interconnection with ESNG.

For several years, CUC had reported a shortfall in its upstream capacity, i.e., it did not have sufficient upstream capacity to meet its design day requirement. The design day requirement is the capacity that the Company would need to transport its estimated volume of firm gas under extremely cold conditions. Although the Company did not have the upstream capacity to meet this demand, in the past CUC had been able to meet its service requirements by acquiring bundled peaking service on the coldest days of the year.

The Company subsequently committed to 30,000 Dths of upstream capacity effective November 1, 2012 as part of TETCO's Team 2012 project. An additional 4,100 Dths of capacity on TETCO is anticipated to go into service November 1, 2013. In the interim, the Company obtained 15,000 Dths of TETCO capacity effective January 1, 2011 and an additional 11,250 Dths effective November 1, 2011. Since incremental upstream capacity requires a corresponding amount of capacity from ESNG, CUC has had to similarly increase its ESNG capacity.

**Q. How much capacity does the Company have available for the current determination period?**

A. The Company currently has total ESNG capacity of 70,163 Dths per day and deliverability of another 10,176 Dths per day from on-system propane air plants, for total firm capacity and deliverability of 80,338 Dths. Given its recent acquisition of TETCO upstream capacity, the Company now has 71,003 Dths per day of upstream pipeline capacity available. The Company's current Supply Plan is based on a design day requirement of 76,395 Dths per day for the current GSR period, increasing to 87,765 Dths per day by the 2015-2016 GSR period.

**Q. Do the Company's demand day projections appear high?**

A. Yes, they do. As shown in the response to DPA-24, the actual peak demand over the past five years was 49,973 Dths. The Company's design day is based on estimated demand given a 15% colder than normal winter, with normal being defined as a ten-year normal. Given the additional capacity acquired by CUC, it appears that the Company has a significant reserve between its capacity allocations and its actual requirements over the past several years. The fact that the Company has not experienced design day conditions does not mean that its design day will not occur, and I recognize that the Company must plan for colder than normal weather. However, given the fact that the Company has not approached design day conditions over the past five years, and given the significant amount of new capacity acquired from TETCO, now may be an appropriate time to review the Company's demand day forecasting methodology. In any case, the methodology should be reviewed prior to the Company acquiring any additional capacity.

**Q. Has CUC also been increasing its capacity on ESNG?**

A. Yes, it has. With regard to downstream capacity from ESNG, CUC has been steadily increasing its capacity allocation. Some of this additional ESNG capacity was acquired in order to serve projected incremental load growth in eastern Sussex County. Unfortunately, the Company's projections of growth in eastern Sussex County have been overly optimistic and ratepayers are paying for significant amounts of capacity in eastern Sussex County that is not being utilized. This is especially troublesome given that the Company's affiliate, ESNG, is the beneficiary of increased capacity payments.

**Q. How much capacity does the Company currently have to serve eastern Sussex County?**

A. The Company has steadily increased its capacity over the past few years. As shown on Schedule N to the filing, the Company has increased its capacity in eastern Sussex County from 2,238 Dths in October 2008 to 8,663 Dths currently, and anticipates another 491 Dths of capacity in April 2012, for a total of 9,154 Dths. As of July 2011, the Company only had 253 residential customers and 56 commercial customers in eastern Sussex County. Total consumption for the period November 2010 to July 2011 was only 368,507 Mcfs and CUC projected sales of another 149,424 Mcfs for the period September 2011 through October 2011.[1] According to the response to DPA-35, the Company received capacity release revenues of $594,180 in 2011 relating to this capacity. In spite of this offset, ratepayers still paid for capacity that was far in excess of what was required to serve customers in eastern Sussex County. In fact, it is unlikely that any new capacity will be required in eastern Sussex County for some time.

**Q. How has growth in eastern Sussex County compared to the Company's projections?**

A. The Company's projections have far exceeded actual growth. As shown in the response to PSC-13, in 2008 the Company projected that by 2012 it would serve 1,414 residential customers in eastern Sussex County. The 2012 forecast was revised downward in 2009 to 763 residential customers. By 2010, the projection for 2012 had fallen further to 629 residential customers. Current projections are that the Company will serve 339 residential customers in eastern Sussex County by October 2012. Similarly, the Company's earlier

1 In Schedule N, the Company reports capacity in Dths but consumption in Mcfs.

projections for commercial and industrial customers also were far higher than the actual number of commercial and industrial customers in that part of its service territory. Since the Company pays these capacity costs to its affiliate, CUC has an incentive to be overly optimistic in its forecast of growth in eastern Sussex County.

**Q. How much of the Company's total demand costs are costs paid to ESNG?**

A. As shown on Schedule F to the filing, the Company's GSR includes total firm gas costs of $36.1 million.[2] Approximately 49.6% of these costs, or $17.9 million, are fixed costs, which the Company must incur, and ratepayers must pay, regardless of sales. Almost 59% of all fixed costs are paid to the Company's affiliate, ESNG. Thus, approximately 29.3% of all costs included in the GSR are costs paid to an affiliate that will not vary with variations in usage.

**Q. Has the Company been increasing the amount of its gas costs that are paid to an affiliate?**

A. Yes, it has. While over the past five years, total gas costs have declined, due to decreases in commodity costs, over the past five years fixed costs increased by almost 50%, from $11.95 million for the twelve months ending October 31, 2008 to an estimated $17.91 million for the twelve months ending October 31, 2012. The average fixed cost per Mcf has increased from $3.52 per Mcf to $5.18 per Mcf. By far, the most significant increases have accrued to the

2 All amounts referenced for the period ending October 31, 2012 have been adjusted to reflect the impact of the

benefit of ESNG. In fact, while total fixed costs have increased by $5.96 million, $2.15 million or 36% of this increase has accrued to the benefit of ESNG.

**Q. Did ESNG recently complete a rate case at FERC?**

A. Yes, it did. It is my understanding that ESNG filed a rate case at FERC on December 30, 2010. CUC intervened in that case, although it did not file testimony and I understand that it did not aggressively participate in efforts to reduce ESNG's request. In fact, according to the response to PSC-11, the parties participating in that case requested that CUC's legal counsel and representatives not participate in settlement discussions. Nevertheless, when the Company prepared its GSR filing, it included estimated ESNG rates, based on its forecast of the rates that were likely to be agreed upon by the parties to the ESNG rate case. As a result of the final settlement agreement in the ESNG rate case, the Company's gas costs paid to ESNG will increase by approximately $110,000 over the costs included in the Company's GSR filing.

**Q. Doesn't the Company credit ratepayers with 100% of the capacity release revenues associated with releases of ESNG capacity?**

A. Yes, it does. However, there is no assurance that CUC will be able to release excess capacity that exists at any given time, or that the rates obtained for this capacity will be compensatory to the costs paid by ratepayers.

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ESNG refund of $2.75 million included in Schedule F.

**Q. What are your conclusions regarding the Company's capacity requirements and associated costs?**

A. The evidence suggests that CUC has no need for additional capacity, over and above what is currently subscribed. Since the Company is now filing an Annual Supply Plan, that plan should be vehicle to assess the Company's need for additional capacity in the future. Therefore, if the Company perceives a need for additional capacity in the future, it should identify this need as early as possible in the Annual Supply Plan. Moreover, it should include in the Annual Supply Plan all documentation and analysis supporting the conclusion that additional capacity will be needed in the future. In this way, the parties will have the opportunity to evaluate any claims for new capacity well in advance of the Company acquiring such capacity. Requiring this need to be identified in the Annual Supply Plan prior to acquiring the capacity will ensure that future capacity is obtained only after a thorough and realistic assessment of the Company's capacity requirements.

Thus, the Company should include in its Annual Supply Plan a discussion of when it anticipates adding any new capacity, either upstream capacity or ESNG capacity. If the Company finds itself requiring additional capacity that was not identified in the Annual Supply Plan, it should notify Staff and DPA and provide an analysis and supporting documentation regarding why this capacity is needed prior to acquiring the capacity. Moreover, this documentation should be provided to the parties in sufficient time to allow the parties a 15 day comment period prior to any capacity agreement being executed by CUC.

In addition, I recommend that the Company review its demand day forecasting methodology to determine if its methodology is still appropriate, or whether there should be some underlying changes in the assumptions or methods used in the Design Day forecast. This review of the Demand Day forecasting methodology should be provided in the Company's next Annual Supply Plan, to be filed in September 2012.

### E. Capacity Release Revenues

**Q. How are capacity release revenues treated for ratemaking purposes?**

A. The treatment of capacity release revenues depends upon the capacity that is being released. Historically, upstream capacity (with the exception of the TETCO capacity) has been included in the Asset Management Agreement. The Company is compensated for revenues relating to releases of this capacity through the fixed payment from the Asset Manager. This payment does not depend upon how successful the Asset Manager is in releasing the associated capacity. Pursuant to a sharing mechanism agreed to in Docket No. 08-269F, ratepayers are credited with 90% of the revenues received from the Asset Manager. The parties agreed that this mechanism would be in place until March 31, 2012, which was the termination date for the Asset Management Agreement when this mechanism was agreed upon. Ratepayers have historically received 100% of the capacity release revenue associated with releases of ESNG capacity, which was not assigned to the Asset Manager.

In last year's GSR filing, the Company included costs associated with new capacity on the TETCO pipeline. The Company did not assign this new capacity to the Asset Manager. In the Settlement Agreement in the last case, CUC agreed to credit ratepayers with 100% of TETCO capacity release revenues "received outside of an Asset Management Agreement…". Moreover, since the Asset Management Agreement was due to expire March 31, 2012, and since the Company agreed to keep DPA and Staff informed about all aspects of the renewal process, it was reasonable to assume that ratepayers would receive 100% of any revenues from release of the TETCO capacity, at least until a new Asset Management Agreement was negotiated.

**Q. Did you raise the issue of transferring control of the TETCO assets to the Asset Manager in the last case?**

A. Yes, I did. On page 36 of my testimony in that case, I stated that, "[i]t is my understanding that this capacity is not currently part of the Asset Management Agreement. Therefore, if the PSC permits the Company to recover costs for this additional capacity from ratepayers, then CUC should market this additional capacity directly…." My concern in that case was that the Asset Management fee was fixed. Thus, I was concerned that if the TETCO capacity was assigned to the Asset Manager, under the existing agreement the Asset Manager would receive 100% of the resulting benefits, while ratepayers would be responsible for paying 100% of the resulting costs. I acknowledged in my testimony that the Asset Management Agreement contained a provision whereby the fee could be renegotiated if additional capacity was assigned to the Asset Manager. However, I stated that "given CUC's history with regard to executing agreements without input from the parties, I recommend that the PSC act affirmatively to ensure that no agreement on this additional capacity will be negotiated without a complete review of the Asset Management Agreement."

**Q. In the last case, did you also recommend that the parties be notified in the event that Chesapeake extended its Asset Management Agreement?**

A. Yes, I did. The Company's Asset Management Agreement was due to expire on March 31, 2012. On pages 38-39 of my testimony in PSC Docket No. 10-296F, I specifically stated, "I recommend that the Company be prohibited from entering into a new Asset Management Agreement or <u>extending the current Agreement</u> without specific input from the parties." (emphasis added) In the Settlement Agreement in that case, the Company stated that it intended to keep the parties informed about its Asset Management procurement process. Specifically, CUC stated that it would provide Staff and DPA with "reasonable information and documents…including but not limited to, (a) a copy of the RFP, (b) the number of entities receiving the Company's RFP; (c) the number of respondents; (d) evaluation criteria; (e) analysis of bids;…" Moreover, the Company stated that this information would be provided "on a rolling basis…and prior to any selection by the Company of an Asset Manager."

In spite of those assurances, the Company has extended its Asset Management Agreement for one year without providing notice to the parties. In addition, according to the response to PSC-25, the Company "amended the asset management agreement to include the

TETCO assets effective November 1, but has retained the right to purchase supply on the TETCO assets from parties other than the asset manager." In that response, CUC also stated that "beginning April 1, 2012, the Company will dispatch supply on TETCO assets prior to requesting nomination on any other assets, thus reducing the Company's reliance on gas from the Gulf of Mexico." With the extension of the Asset Management Agreement, the fee paid by the Asset Manager increased, with 90% of this fee being credited to ratepayers.

**Q. Were the parties kept informed about the status of the negotiations when the current Asset Management Agreement was extended?**

A. No, they were not. Although issues regarding the Asset Management Agreement had been raised in prior cases and although I raised concerns about transferring the TETCO capacity to the Asset Management Agreement, the parties were not consulted when the current Asset Management Agreement was being negotiated. In spite of the fact that CUC had stated it would keep the parties informed about its Asset Management solicitation activities, no information was provided until the Asset Management Agreement was executed. This is another example of the Company failing to keep the parties informed about decisions that ultimately impact upon the costs passed through to ratepayers. Moreover, not only was the Asset Management Agreement extended, but the TETCO capacity was transferred to the Asset Manager. In my opinion, this constituted a violation of the spirit, if not the letter, of the Settlement Agreement.

**Q. Why are you particularly concerned about the transfer of the TETCO capacity to the Asset Manager?**

A. I am concerned for two reasons. First, ratepayers are committed to paying for significant capacity costs relating to the TETCO capacity. Therefore, it is imperative that capacity release revenues are maximized in order to mitigate the demand costs that would otherwise be paid by Delaware ratepayers. Second, the transfer of this capacity to the Asset Manager may have been an attempt to circumvent the PSC's finding in PSC Docket No. 08-269F. In that case, the PSC found that when CUC released capacity to an affiliate, it should credit the GSR at the full max rate for that capacity. The PSC found that this requirement was consistent with the Company's cost allocation manual and code of conduct relating to affiliated transactions. Selling this capacity to an affiliate at less than max rate would require regulated gas utility ratepayers, who are paying for these capacity costs through their GSR rates, to effectively subsidize CUC's unregulated operations. Thus, the PSC found that ratepayers should be made whole for any capacity sold to an affiliate.

CUC has indicated that at the present time, the Asset Manager is not releasing this capacity to any affiliates although it may be using the capacity to transport gas sold to affiliates of the Company.

**Q. What do you recommend?**

A. Given the Company's decision to extend its Asset Management Agreement, the current agreement will now terminate on March 31, 2013. I recommend that in its next GSR filing, the Company should be required to provide a specific timeline for solicitation of a new Asset Management Agreement. Moreover, the Company should identify in its GSR filing all assets that it is proposing to include in the solicitation. One of the requirements of the new agreement should be disclosure of all transactions executed by the Asset Manager with affiliates of the Company. CUC should also address the steps that it will take to ensure that all transactions executed by the Asset Manager are consistent with the PSC's directives in PSC Docket No. 08-269F with regard to affiliate transactions. While I understand that the Company may not have finalized its plans to solicit a new agreement by the time it files its next GSR, it is important to begin a discussion of these important issues well before the actual solicitation occurs.

### F. <u>Gas Commodity Costs</u>

**Q. Has the Company implemented a Gas Hedging Program in an effort to control variability in commodity costs?**

A. Yes, it has. As a result of concerns raised in prior GSR proceedings regarding the commodity costs being incurred by CUC, the parties entered into a Stipulation in the Company's 2006 GSR proceeding (Docket No. 06-287F) that established a hedging program effective July 1, 2007. In that case, the parties agreed to a Gas Hedging Plan that permitted the Company to hedge 70% of its firm supply requirements over a twelve-month period prior to the month of delivery. 30% of the hedged volumes are "hedged" at market price. Thus, the plan contemplates that approximately 50% (70% less (70% X 30%)) of the Company's firm supply requirements will effectively be hedged prior to the month of delivery.

The Gas Hedging Plan details how and when the gas hedges will be placed. The Gas Hedging Plan also addresses credit factors and certain other issues. The Company is limited to physical hedges at this time. On a quarterly basis, the Company files Gas Hedging Reports, showing the results of its gas hedging activities. In addition, the parties hold a meeting or conference call each quarter to review the results of the Company's quarterly hedging activities. The Stipulation also required the filing of an Annual Report and a review of the Plan after two years.

**Q. Were there any changes subsequently approved to the Gas Hedging Plan?**

A. Yes, as part of the Settlement Agreement in PSC Docket No. 09-398F, there were some minor modifications made to the Gas Hedging Plan. Specifically, the parties agreed to accelerate purchases of hedges in the event that natural gas prices for a specific delivery month decreased below 75% of the weighted average cost of gas used in the most recent GSR filing. The degree of the acceleration depends upon the magnitude of the decline in natural gas prices. Similarly, the parties agreed to delay purchases of gas hedges if natural gas prices rose above 125% of the weighted average cost of gas used in the most recent GSR filing. Once again, the degree of the delay depends upon the magnitude of the price increase. This flexibility can be executed by the Company without prior notification to the Staff and DPA. However, the Company must inform the parties about any such actions within five business days. In the event that gas hedges are accelerated or curtailed according to these provisions, the revised procurement plan contains a true-up mechanism that can be used in subsequent months.

The revisions do not permit CUC to increase its total hedges for any particular month above the current eligible portfolio, which is defined as 70% of the Company's gas supply requirements. If the Company wants to exceed the 70% threshold, it must obtain prior approval from the parties.

In addition, in last year's GSR proceeding, the Company agreed to track and monitor a dollar-cost averaging mechanism that was recommended by Staff. The intent of this requirement was to determine if ratepayers and the Company would benefit from the adoption of a dollar-cost averaging mechanism for hedging natural gas.

**Q. What were the results of the Company's Gas Hedging Plan over the past year?**

A. While there was some month to month volatility in gas prices, overall prices declined during the twelve months ending October 2011. According to Chesapeake's Annual Gas Hedging Report, which was submitted for the twelve months ending October 31, 2011, the Company's actual cost of gas was $3.08 million, or approximately 15.7%, above the NYMEX last day settle prices for the period November 1, 2010 through October 30, 2011.[3] I believe that the last day settle price is the best measure of the success of the Company's Gas Hedging Program, since that is the price at which the Company would acquire the majority of its

3 The Company's actual cost of gas was approximately $695,000 below the average NYMEX high/low of the preceding twelve months. However, I do not believe that this comparison is as meaningful as the comparison to NYMEX settle prices.

market-priced supply in the absence of the program. In a period of declining prices, one would expect that the Company's hedging costs would exceed the NYMEX settle.

**Q. What were the results of the dollar-cost averaging analysis submitted by Chesapeake?**

A. In response to Staff's request, the Company submitted a dollar-cost averaging analysis for the period November 1, 2010 through October 31, 2011. On a cumulative basis, this analysis indicated that 4% more gas would have been hedged had the Company utilized the dollar cost averaging approach. The overall impact on the hedged price would have been a reduction of approximately 1.4%.

**Q. Is the Company proposing any changes in this case to its gas hedging program?**

A. No, it is not. The Company is not proposing any changes to the program at this time. The Company is proposing to continue to analyze the impact of dollar-cost averaging and to report the results on a quarterly basis.

**Q. Do you agree with the Company that no changes should be made at the present time?**

A. I concur that the Company's program is working relatively well. However, given the recent decline in natural gas prices, the parties are discussing whether it would be appropriate to accelerate purchases of natural gas at this time and/or to adopt a dollar-cost averaging mechanism. The parties are monitoring the natural gas market and discussions are continuing. The next formal review of the Company's gas hedging program will take place next year. If the parties have not agreed upon any revisions in the interim, then in that review we can examine whether dollar-cost averaging should be adopted and/or if other changes should be made to the Company's gas hedging program.

**Q. Does this complete your testimony?**

A. Yes, it does.